International Basic and Applied Research Journal

Research Article (Subject – Petroleum Geology)

Characterization of R8-Reservoir Zone in Ataga Oil Field, Shallow Offshore Niger Delta

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Received: 27 March 2017, Revised Received: 18 April 2017, Accepted: 24 April 2017

Abstract

The objective of this paper is to present the result of characterization and modelling of R8- reservoir zone of the Ataga oilfield, Niger Delta. The Ataga oilfield is located in the eastern part of the Niger Delta sedimentary basin and covers an area of 43.84km^2. Subsurface data for Ataga oilfield are 3 –D seismic data and well logs data for six wells. Nine reservoirs (R1 to R9 reservoirs) were delineated based on integrated interpretation of well data (gamma ray logs, neutron logs and density logs) and correlation in Ataga oilfield. Deep resistivity logs indicated five reservoirs as hydrocarbon bearing; however, R8-reservoir was identified, interpreted and characterized. Environment of deposition of R8-reservoir was interpreted as fluvial/tidal channel overlaid on shoreface sand bodies within the delta front setting and it pay thickness ranges from 10 to 95m with estimated porosity and net – to- gross of 19 - 24% and 63 - 85% respectively, low water saturation of 13 – 38% reflect good hydrocarbon accumulation within R8-reservoir. Faults and horizons that correspond to the top and base of reservoir R8 were interpreted across Ataga field, this interpretation were to defined structural maps used as input for map and model based analysis. Map and model based volumetric methods were utilized to estimate the volume oil accumulation in R8-reservoir in order to compare the result. Stock tank oil initially in place (STOIIP) estimated with map based volumetric method has an average volume of 97.0MMstb while stock tank oil initially in place (STOIIP) estimated with model based volumetric method has an average volume of 97.8MMstb and there was no significant difference in the estimated STOIIP using map and model based methods.

Keywords: Seismic/Static modeling, Heterogeneity, Porosity, Permeability, Hydrocarbon volume, Shallow offshore, Niger Delta.

Introduction

Hydrocarbon reservoirs contain multiphase of water, oil and gas and the occurrence of each phase is dependent on the structure and pressure in the reservoir. Few decades ago, oil fields were very easy to find and exploit and most of the oil fields were discovered onshore but nowadays due to the need for fossil fuel energy and depletion of onshore oil resources, offshore areas are becoming more popular. After the field has been discovered through a discovery wells, conventional oil field development begins and is optimized by the generation of prospect with good certainty in regards to geologic structure

and rock properties as porosity, oil saturation, permeability and other parameters obtained from the geological interpretation.

Maps has been the method of representing geologic structures and rock properties but its application in reservoir geology has some inherent limitations because, it is impracticable to represents 3-D reservoir heterogeneity with 2-D map (Deutsch and Journel, 1998) therefore, there is a need for 3-D characterization and modelling of reservoir which allowed for the heterogeneous nature of the said reservoir to be represented through integration of available data. Reservoir characterization is the process of constructing a spatial distribution of reservoir properties; porosity, permeability and facies across the reservoir based on interpreted or estimated information obtained from geological and geophysical datasets (Journel and Huijbregts, 2003). Reservoir model is an excellent tool for communicating reservoir structures and distribution of petrophysical properties to non-geoscientists and provides the most likely pre-drill prediction of reservoir characteristics and enhance post-drill of reservoir characterization away from well locations.

Objectives

This study involves integration of geophysical data interpretations to build 3-D reservoir characterization model for R8 - reservoir in Ataga field, shallow offshore Nigeria for optimum hydrocarbon estimation. This was archived through Well log interpretation/correlation, integrated seismic interpretation of Ataga oilfield was integrated, petrophysical estimation of reservoir properties, which provided the key constrain for the definition of rock properties and also serve as input parameters for reservoir modelling. This project aimed at building a of R8-reservoir, estimate the volume of hydrocarbon accumulation in R8 – reservoir using both map and model based methods and to compare the hydrocarbon volumes estimated with map and model based volumetric methods.

Location and geology of the study area

The study area is located within Niger Delta, southern Nigeria (Fig. 1). The Niger Delta sedimentary environment is a prolific petroleum province and it covers an area defined by latitude 3^0 - 6^0N and longitude 5^0 - 8^0E with an overall regressive clastic sediments thickness of about 12 km (Evamy et al, 1978).

Geology and Stratigraphic setting of the Niger Delta

The Niger Delta province is delineated by the geology of southern Cameroun stable megatectonic frames and West African shield, these include; Benin and Calabar hinge lines at the northwestern and eastern boundaries of the delta respectively. However, the Gulf of Guinea borders the Niger delta basin in the south and the base of the Benue Trough, Anambra Basin and Abakaliki High complete the northern boundary. This configuration of the basin reflects the overall regression of depositional environment within the Niger delta clastic wedge (Oyedele et al., 2013).

The Akata, Agbada and Benin Formations lithostratigraphic units (Fig. 2) have been defined as the subsurface stratigraphy of the Niger Delta with its ages decreasing basinward that is, from Eocene to Pleistocene times and corresponds to Northern - Offshore depobelts which reflect an overall regressive or shoaling sequence. Generally, the formations are coarsening-upward progradational clastic deposited in marine and non-marine environments (Weber, 1987). The age of Akata Formation has been reported between Paleocene to Recent and its lithologies composed of shale and silts with streaks of turbidites sand (Doust and Omatsola, 1989). These shale were deposited during the early stages of Niger Delta

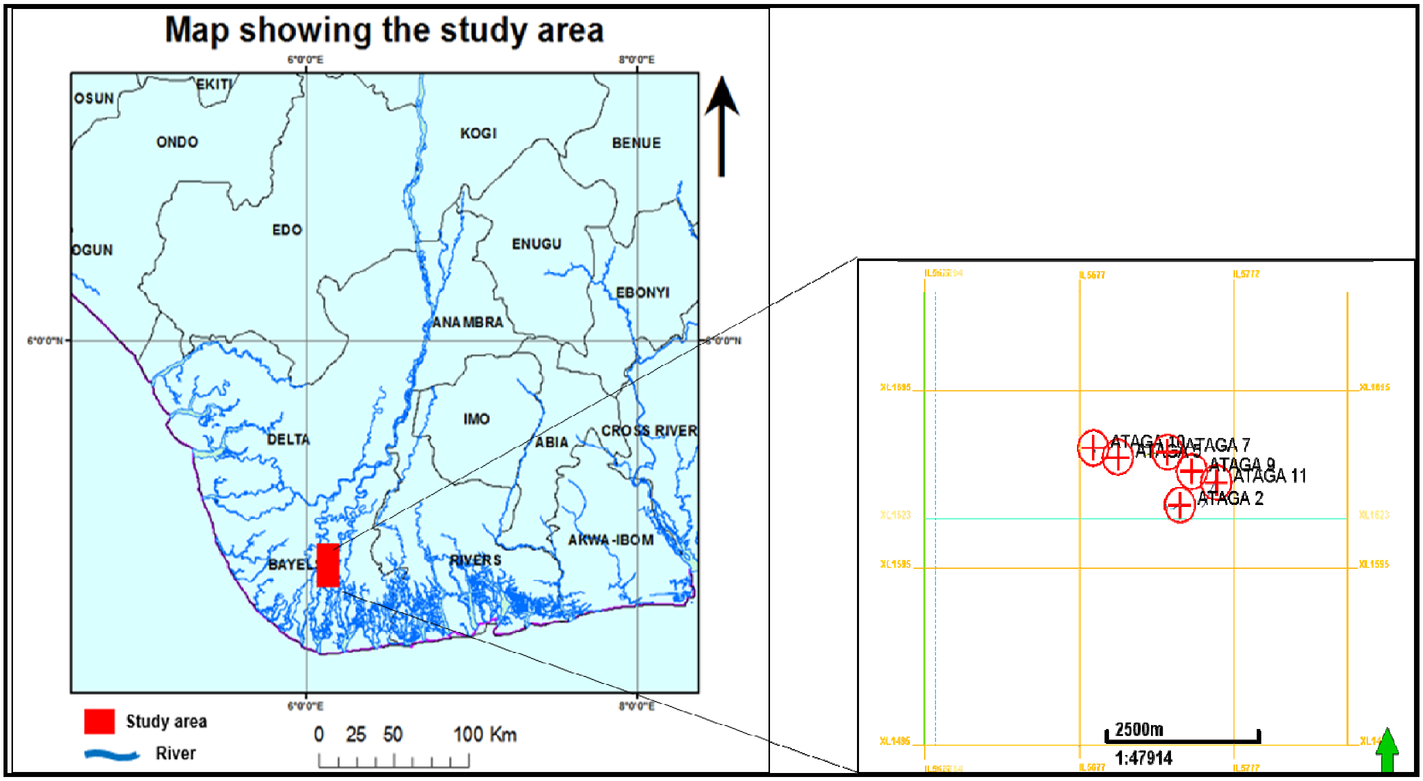

Fig. 1. Location and base map of the study area.

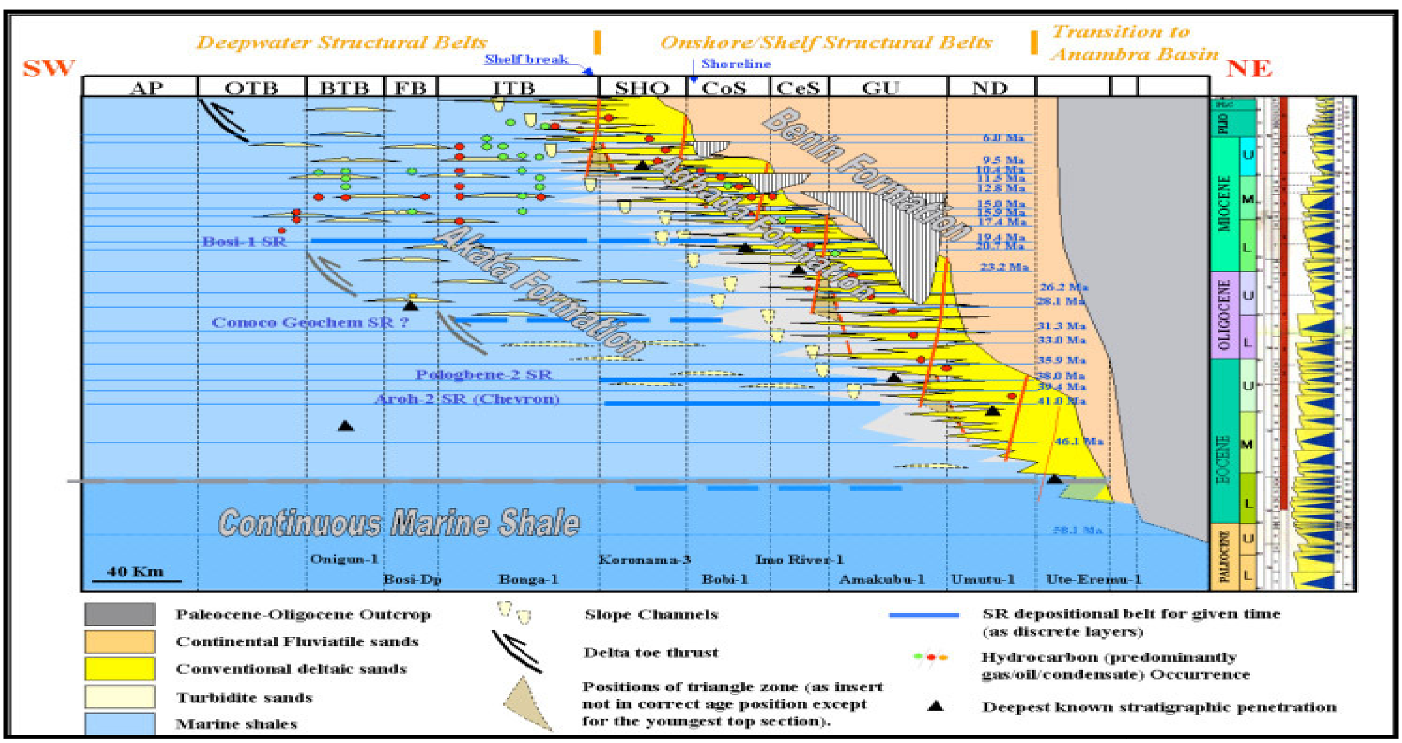

Fig. 2. Stratigraphic column of Niger Delta (Ejedawe, 2012).

progradation and where exposed onshore are designated as Imo Shale. The Akata shale deposits are interpreted as deep water lowstand system tract deposits and are typically over pressured (Stacher, 1995). However, the Agbada Formation on the other hand has a maximum thickness of about 3500m and occurs throughout the basin. Its lithologies consist of intercalations of sands and silts with shale stacked in prograding pattern as defined by increase in sand grains and bed thickness from bottom to the top. The age of Agbada Formation as reported is between Eocene to Pleistocene and it is interpreted to be deposited in a fluvial-deltaic environments.

The youngest formation in the Niger Delta lithostratigraphic setting is the Benin Formation, its age ranges from Oligocene to Recent and outcrop as the present delta surface. The base of Benin Formation, indicated by the youngest marine shale is placed at a depth of approximately 1500m. The Benin Formation lithologies therefore composed of sand and have been interpreted to be deposited in an alluvial or coastal plain environment (Doust and Omatsola, 1989).

The Agbada Formation deposits and turbidities sands embedded in Akata Formation are considered to house all the petroleum elements that cooked, generated, migrated and preserved the oil and gas in Niger Delta basin. Doust and Omatsola, (1989) reported that, the ratio of gas to oil within a depobelt increase southward, although its distribution is complex. Reservoir units in Niger Delta basin has been described as deposits of fluvial, deltaic and deep water turbidities sands, these sands units are unconsolidated with minor argillaceous and siliceous cements (Kulke, 1995). Conversely, Edwards and Santogrossi (1990) reported that most of the reservoirs in Niger Delta basin are sands of Miocene epoch with average porosity and permeability of 35% and 2mD respectively. The reservoirs rock in Niger Delta ranges in thickness from about 15m to greater than 50m (Evamy et al, 1978).Structural and stratigraphic trapping configuration are also reported in Niger Delta basin. However, formation of structural traps as reported by (Evamy et al, 1978; Stacher, 1995) were developed during syn-sedimentary deformation of Agbada Formation while depositional processes that produces paleo-topographic high encased in impermeable rock and are preferentially occur along the structural flanks resulted to the formation of stratigraphic traps (Beka and Oti, 1995).

Materials and Methods

3-D Seismic volume, checkshot and well logs datasets from six (6) wells in Ataga field were provided by SPDC, Port Harcourt for this study and were interpreted using Petrel software. Gamma ray (GR), neutron porosity (NPHI) and bulk density (RHOB) logs were integrated to delineate non-reservoir rock from reservoir rock and resistivity (ILD) logs was interpreted to differentiate between the formation fluids (hydrocarbon or water) within the reservoir intervals. Integration of NPHI and RHOB logs were interpreted to discriminate between hydrocarbon types (gas or oil) within the reservoir. Environments of deposition was interpreted based on facies analysis of gamma ray log motifs and standard formulae were used to estimate petrophysical parameters; gross reservoir thickness, net reservoir thickness, porosity and water saturation from logs data.

Normal faults were identified and interpreted along the cross lines on Ataga seismic data with a bin spacing of 50m. Well to seismic tie relates the interpreted well information to seismic data and seismic reflections were identified, which correspond to the top and base of R8 - reservoir and were interpreted on both inlines and crosslines on Ataga seismic data with a bin spacing of 50m to generate time structure maps and time – depth relationship

obtained from well to seismic tie was used to convert the maps to depth structure maps..

The interpreted faults and surfaces were input to build a 3D skeleton grid for the static model. The area extent of the model (10.54km^2) was defined by the limit of anticlinal and fault supported structural closure and geostatistical algorithm (Sequential indicator simulation and Sequential Gaussian simulation) to populate the structural model with up-scaled lithofacies and estimated petrophysical properties respectively. Lithofacies was distributed across the structural model to depict the interpreted subsurface facies distribution and was used to constraint the distribution of petrophysical properties (net to gross, porosity and water saturation) within the model.

Stock tank oil initially place (STOIIP) for R8-reservoir was estimated with map and model based volumetric methods and the results were tested for significant differences using paired t – test hypothesis test. In both situations, the standard estimation formula stated below was used.

$$\boxed{N = 7758Ah\phi(1 - S_{\mathrm{w}})/B_{\mathrm{oi}}}$$

Where;

N = STOIIP (STB)

7758 = Conversion factor from acre-ft to bbl

A = Area of reservoir (acres) obtained from map and model

h = Reservoir pay thickness (ft)

ø = Reservoir porosity

S_w = Water saturation

B_{oi} = formation volume factor for oil at initial conditions (reservoir bbl/stb) and was taken as 1.0bbl/stb.

Results and discussion

Nine reservoirs denoted as R1 to R9 - reservoirs were delineated and correlated across Ataga wells based on well logs interpretation; however, this project focused on reservoir characterization of R8 - reservoir (Fig. 3a &b).

Gamma ray logs motifs trends were applied to R8 - reservoir to interpret its environments of deposition (EOD). An increase in gamma ray value depicts upward trend (fining upward sequence) with sharp base and was observed from all the wells in Ataga field for R8 – reservoir. However, this suggests that R8 - reservoir is becoming clay-rich upwards and may be interpreted as a fluvial, tidal channel admixture distributary channel environments overlain on a basal Upper shoreface depositional environment which shows a decrease in gamma ray value with an overall coarsening upward sequence trend as presented in Fig. 4.

In this study, the R8 - reservoir zone was evaluated for its reservoir thickness, pay thickness, net – to – gross, porosity, water saturation and the result is presented in Table 1. However, the reservoir thickness for R8 - reservoir ranges from 106 to120m (SSTVD) while the pay thickness ranges from 10 to 95m (SSTVD) with good porosity and net-to- gross of 19 - 24% and 63 - 85% respectively. The relatively low water saturation (13 – 38%) within this zone reflects a good hydrocarbon accumulation within the reservoir.

Furthermore, Table 1 below reveals the statistical evaluation of the encountered petrophysical properties of the analyzed well in this study. The reservoir thickness and NTG in Ataga-11 well has been drastically reduced due the interplay and continued

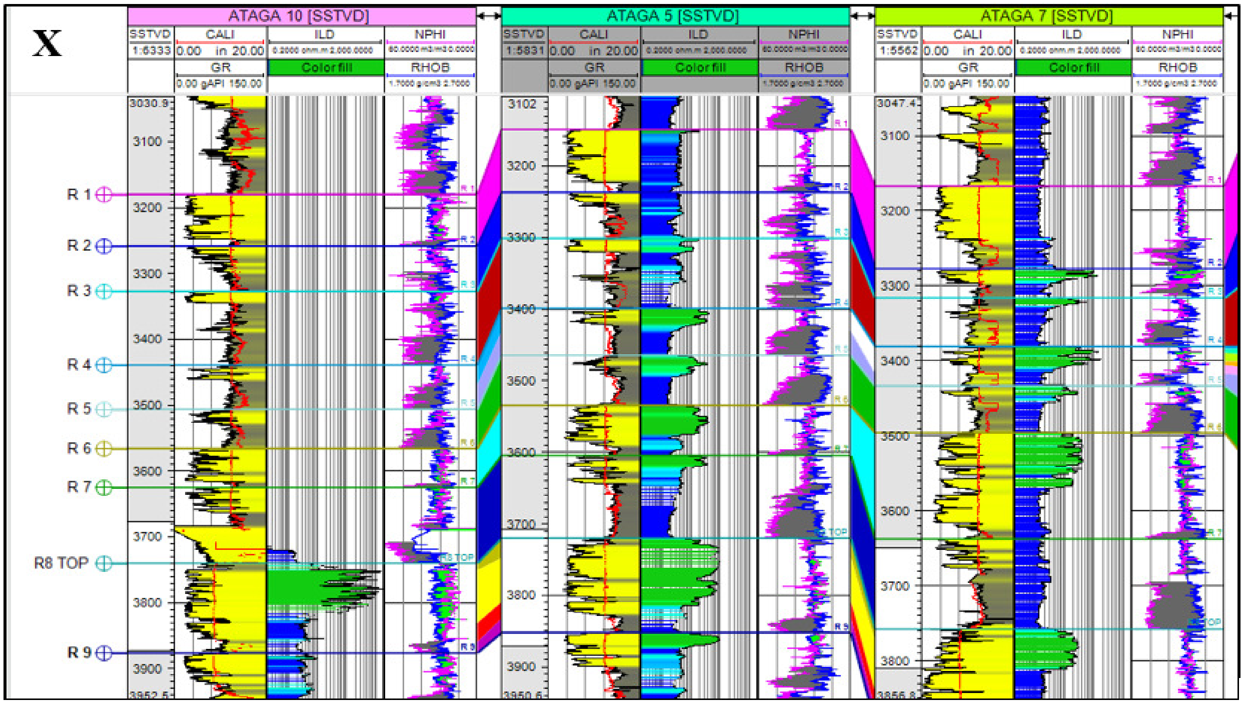

Fig. 3a. Well logs interpretation and correlation.

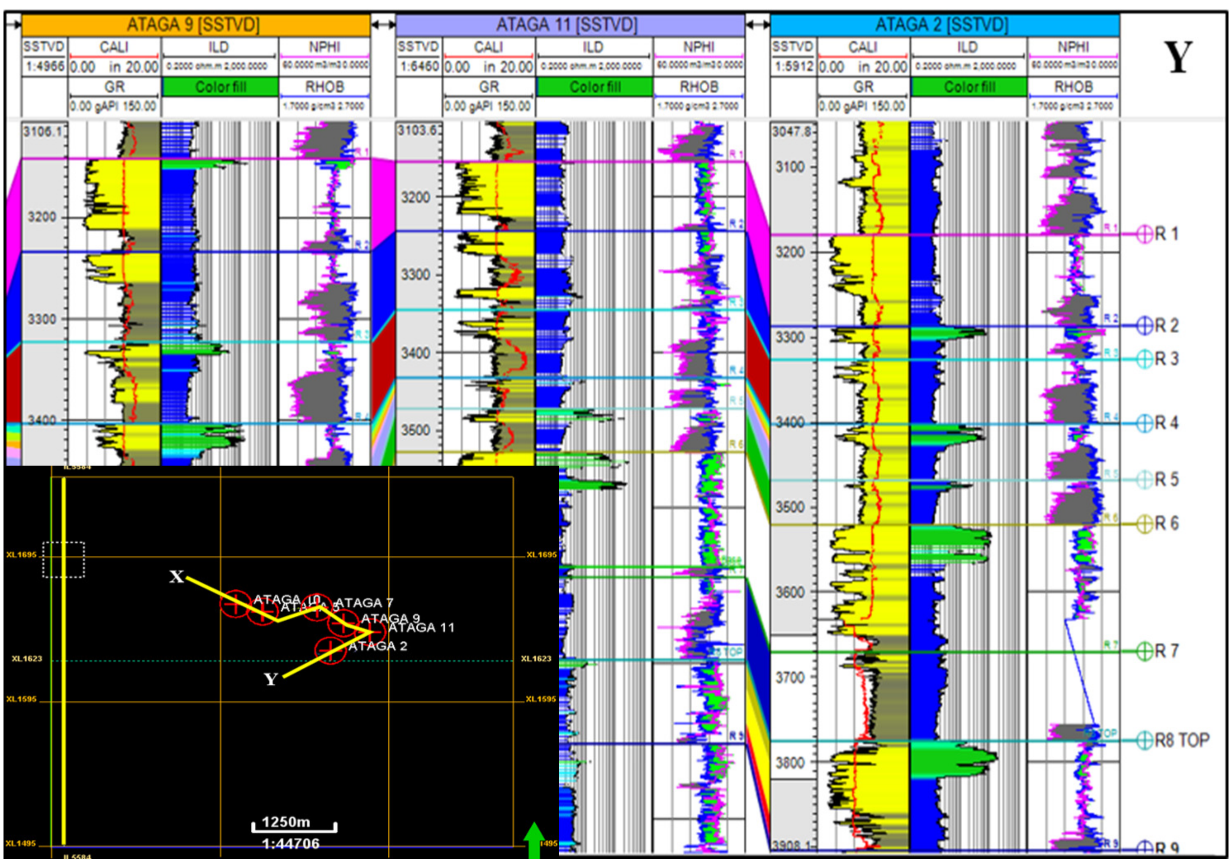

Fig. 3b. Continuation of well logs interpretation and correlation.

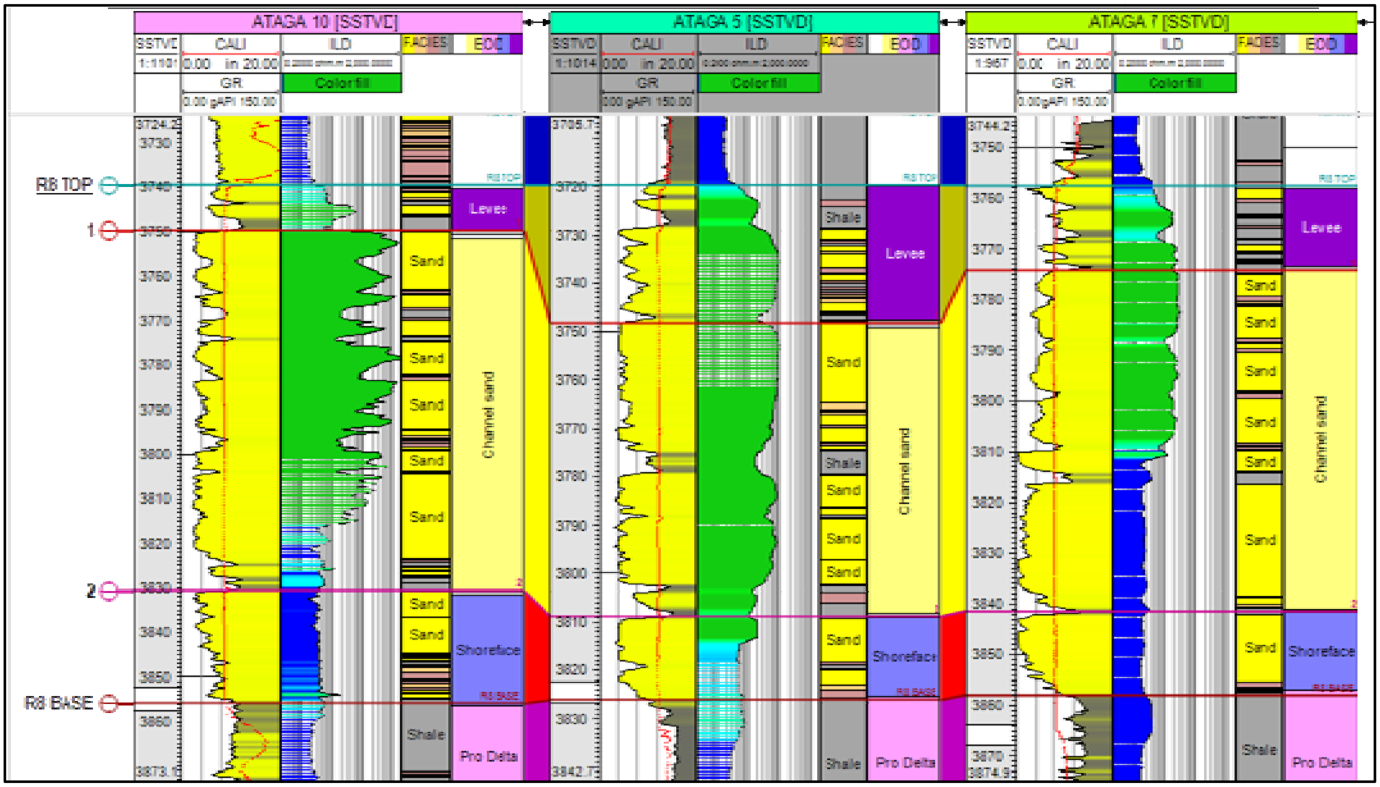

Fig. 4. Lithofacies and environment of deposition interpretation for R8-reservoir.

Table 1. Petrophysical properties of R8-reservoir.

Well/Properties	**ATAGA -10**		**ATAGA- 5**		**ATAGA -7**		**ATAGA -11**		**ATAGA -2**	
	MD	**SSTVD**	**MD**	**SSTVD**	**MD**	**SSTVD**	**MD**	**SSTVD**	**MD**	**SSTVD**
Top (m)	3758	3739	3741	3719	3800	3757	3829	3795	3799	3775
OWC (m)	3829	3815	3836	3814	3855	3812	3840	3805	3841	3816
Bottom (m)	3875	3858	3853	3831	3906	3863	3926	3915	3915	3890
Reservoir thickness (m)	117	119	112	112	106	106	97	120	116	115
Pay thickness (m)	71	76	95	95	55	55	11	10	42	41
NTG	0.85		0.75		0.77		0.63		0.69	
Net Pay thickness (m)	60.35	64.6	71.25	71.25	42.35	42.35	6.93	6.3	28.98	28.29
Porosity	0.21		0.2		0.19		0.24		0.19	
Water saturation	0.13		0.21		0.33		0.38		0.22	
Note: MD = Main Depth and SSTVD = Subsea True Vertical Depth										

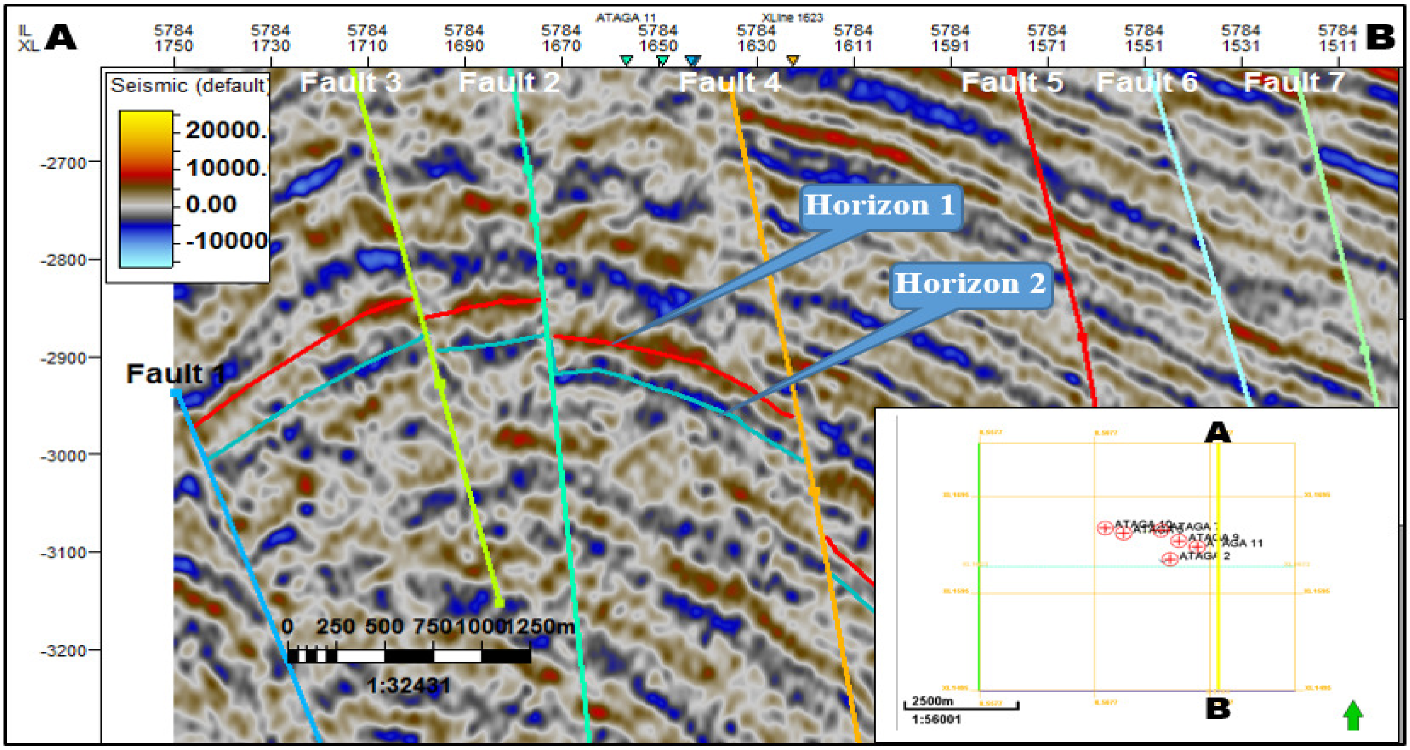

Fig. 5. Fault and horizon interpretation.

deposition of intra reservoir shales and channel heterolithics. A corresponding and noticeable deduction in the resistivity was observed which have intensively caused invariably reduction in the overall pay thickness. It is however suggested that this zone may contain pyritized and/or clay minerals which causes the perceptible low resistivity.

The result of well to seismic tie relationship shows that, the top and base of R8 reservoir corresponds to a peak and trough respectively; therefore, the seismic data is display in a zero phase.

The interpreted horizons (Fig. 5) which represent the top and base of R8 - reservoir were gridded to time maps using convergent interpolation algorithm as interpolation method, this maps were converted to depth maps using velocity information from well to seismic tie (Figs. 6a & b).

The result of R8 - reservoir (Fig. 6) facies modelling indicate high sand to the shale proportion, this conform to the geologic knowledge of most reservoir in Niger Delta, which is sand rich with shale intercalations. Apart from having a good structural closure as seen on the depth structure map, the facies model of R8 - reservoir shows that, R8 - reservoir is rich in sand content. Facies model for R8 - reservoir was used to constrain the distribution of the petrophysical properties (net-to-gross, porosity and water saturation) as shown in Fig. 7.

Map and model base volumetric methods were utilized to estimate the volume oil accumulation in R8 - reservoir and the results compared. The deepest oil water contact (OWC) in R8 - reservoir was superimposed on the depth structure map to define the area of oil accumulation (Fig 8).

Three average values of net - to - gross (NTG), porosity (ϕ) and water saturation (S_w) together with R8 - reservoir structural maps (top and base) and the contact (OWC) were inputted into the map and model

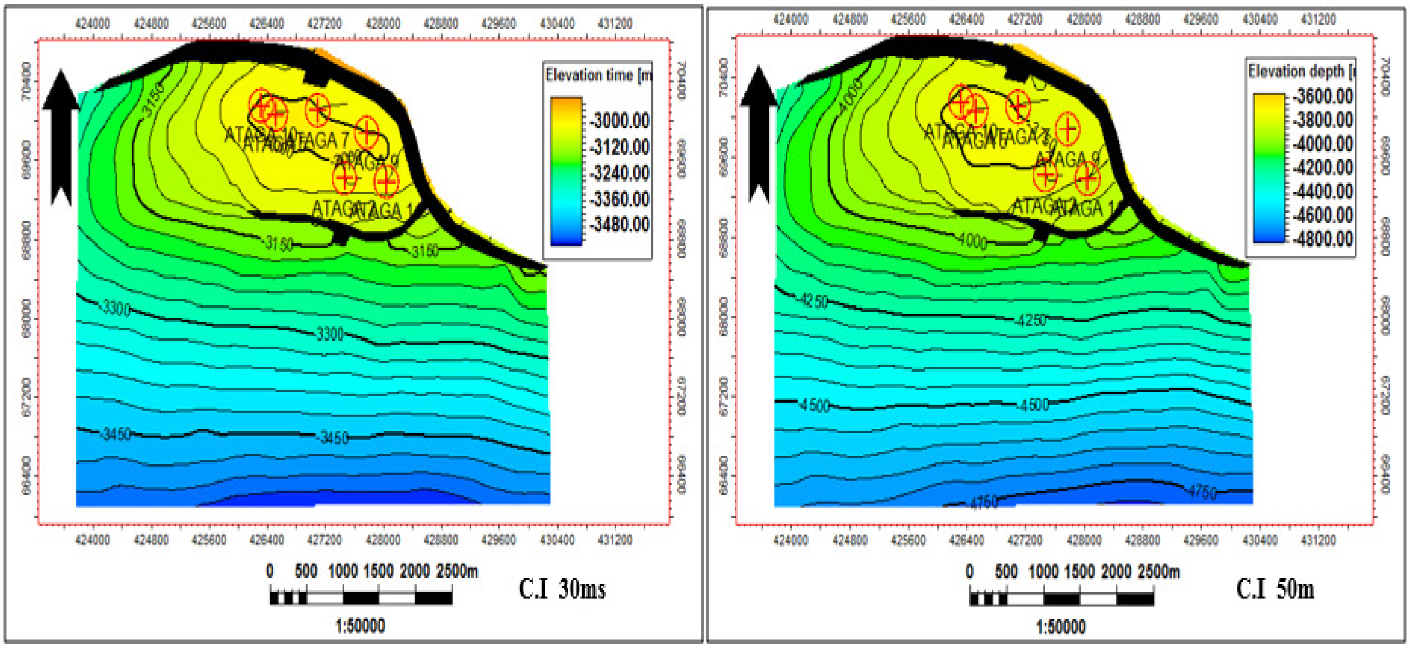

Fig. 6a. Time and depth structure map for top of R8-reservoir.

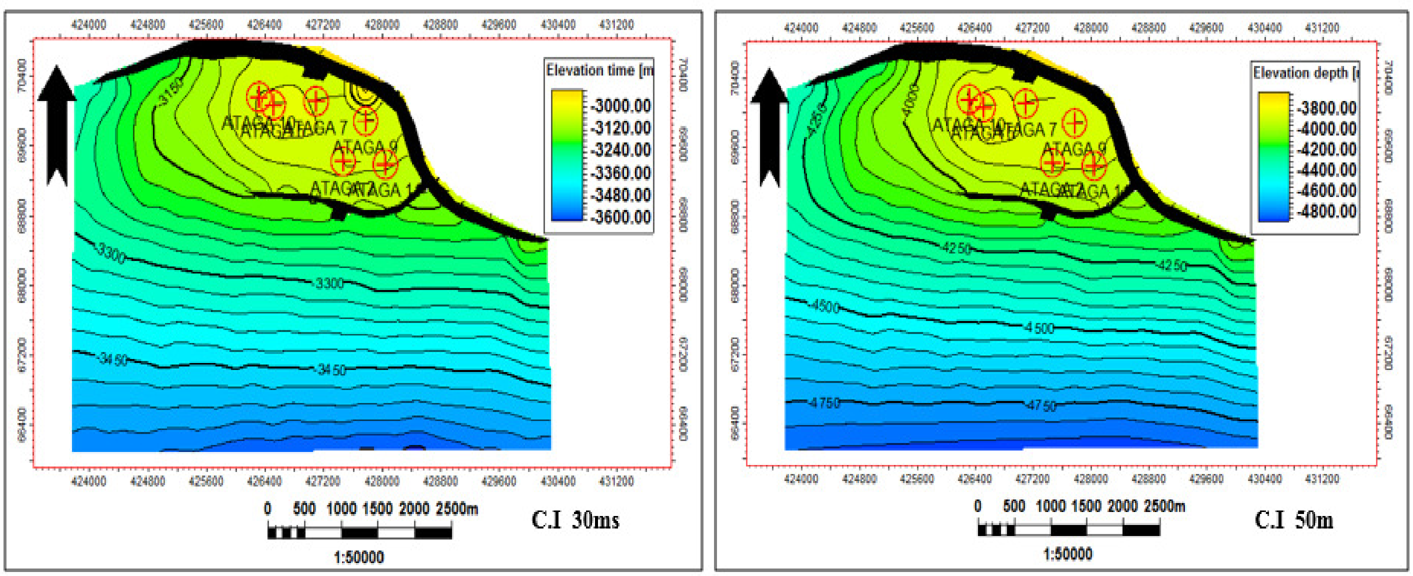

Fig. 6b. Time and depth structure map for base of R8-reservoir.

based volume calculation workflow in Petrel software to estimate the gross rock volume and stock tank oil initially in place (STOIIP) for ten (10) scenarios using Monte Carlos simulation. The result indicated that, the average values of STOIIP estimated with map and model based volumetric methods are 97 and 97.8MMstb respectively (Table 2 and 3).

Paired t – test was conducted to compare the estimated STOIIP using the map and model based volumetric methods.

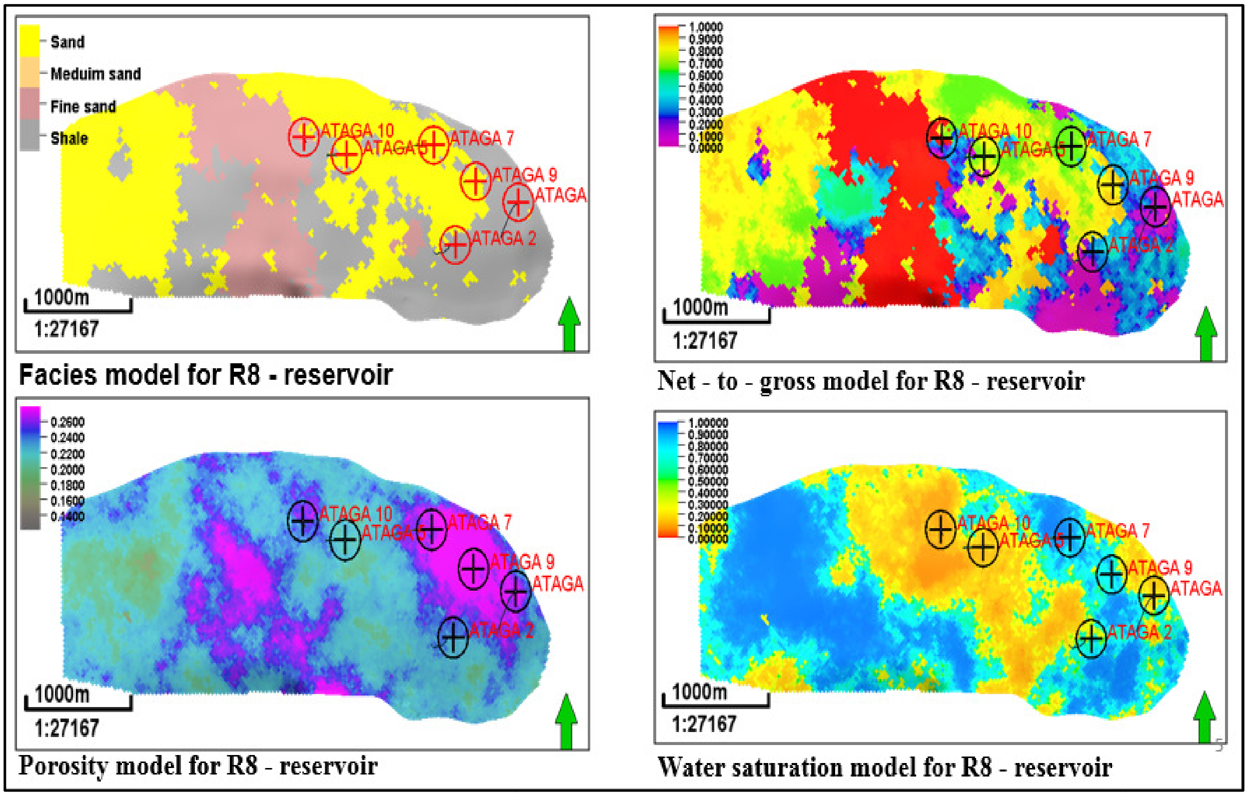

Fig 7. R8 – reservoir properties modelling.

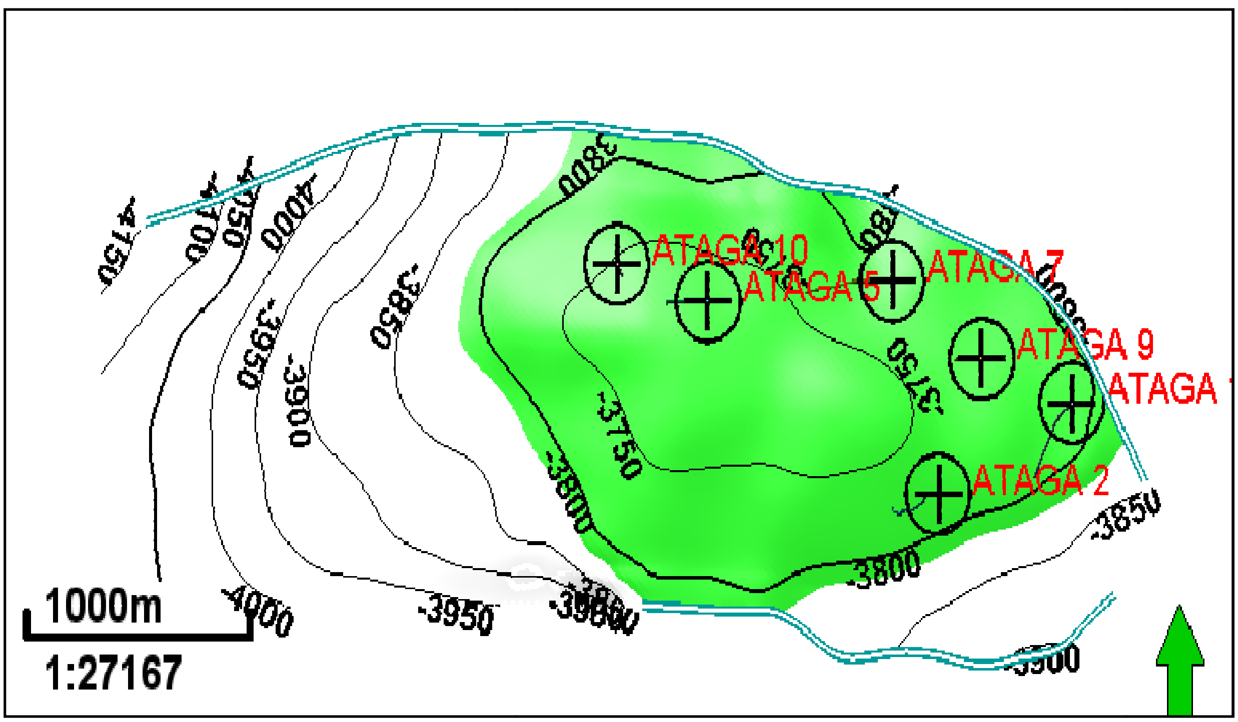

Fig. 8. R8 - reservoir contact map.

Table 2. STOIIP parameters and result (Map based).

Scenarios/Parameters	Bulk Volume (acre*ft)	NTG	Porosity	S_w	B_0	STOIIP (MMstb)
Case 1	115180	0.66	0.26	0.01	1	149
Case 2	115180	0.61	0.15	0.35	1	53
Case 3	115180	0.61	0.21	0.22	1	90
Case 4	115180	0.94	0.15	0.32	1	88
Case 5	115180	0.69	0.16	0.14	1	87
Case 6	115180	0.60	0.20	0.04	1	105
Case 7	115180	0.84	0.25	0.22	1	150
Case 8	115180	0.80	0.17	0.32	1	82
Case 9	115180	0.67	0.24	0.22	1	109
Case 10	115180	0.59	0.15	0.27	1	59

Table 3. STOIIP parameters and result (model based)

Scenarios/Parameters	Bulk Volume (acre*ft)	STOIIP (MMstb)
Case 1	120886	100
Case 2	120886	98
Case 3	120886	102
Case 4	120886	103
Case 5	120886	89
Case 6	120886	98
Case 7	120886	105
Case 8	120886	90
Case 9	120886	96
Case 10	120886	97

Test hypotheses

Null: There is no significant difference between the map and model based estimated STOIIP.

Alternative: There is significant difference between the map and model based estimated STOIIP.

The paired T – test result shows that, t– Crit. > p-Value; therefore, null hypothesis was accepted; thus, there was no significant difference in estimated STOIIP using the map and model based volumetric methods at 0.05 significant level (Table 4). These result suggest that STOIIP estimated for R8 - reservoir in Ataga field using the map and model based

Table 4. T – test result for estimated map and model based STOIIP.

STOIIP	n	Mean	SD	df	HMD	t–cal.	t–crit.	p-value	Decision
Map Based	10	97.1	32.65	9	0	0.9467	2.2622	0.05	Accept
Model Based	10	97.8	5.20	-	-	-	-	-	-
n = Observations, SD = Standard deviation, HMD = Hypothesized mean difference.									

volumetric methods is similar provided the methodology used in this project is followed.

Conclusion

The lithology encountered within the R8-reservoir zone comprises of predominantly sand and shale with intercalation silts. The encountered facies within the wells comprises of channels, barrier bars complexes, delta-marine fringes and restricted mudstones. However, the environments of deposition/facies delineated in this study consist of channels, shoreface sands (upper and lower shorefaces), heterolithics and shales. These depositional settings were identified from log motifs based on their smooth/cylindrical, blocky (erosional base), funnel and bell shapes respectively. Channel sands are cylindrical, blocky, serrated and in some cases have fining upward pattern at their tops and their readings ranges from 20–70[g(API)] and they have flat bases. The Upper shoreface sands on the other hand are blocky with reading range of 30 - 60[g(API)]. Conversely, lower shoreface sands have a coarsening upward sequence pattern and sometimes exhibited a 45 – 90[g(API)] range readings. The shales are either marine shales or Coastal plain shales, their reading ranges from >100 - 150 [g(API)] while heterolithics deposits (almost equal propositions of sand and shale) reading ranges from <100[g(API)]. The average computed reservoir thickness, pay thickness, net pay thickness, NTG, porosity and water saturation for the R8-reservoir zone was 114.4m, 55.4m, 42.6m, 0.74%, 0.21%and 0.25% respectively. A lithostratigraphic correlation of the zone utilizing determined petrophysical properties within the six wells elucidate the identification of the environments of deposition throughout the wells. Stock tank oil original in place (STOIIP) estimated with the map based volumetric method for R8 - reservoir ranges from 53 to 150MMstb with an average volume of 97.1MMstb.However, STOIIP estimation with the model based volumetric method for R8 - reservoir ranges from 89 to 105MMstb with an average volume of 97.8MMstb.

Acknowledgement

Shell Petroleum Development Company (SPDC) is well appreciated for the release of the data for this study and donating Petrel workstation used for interpretation in the department of Geology, University of Port Harcourt.

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Cite this article: Tobby, U., Udofia, M., Avwunudiogba, A. and Ugwueze, C. 2017. Characterization of R8-Reservoir Zone in Ataga Oilfield, Shallow Offshore, Niger Delta. International Basic and Applied Research Journal, Volume 03, Number 06, pp. 1-13.

